

## Meeting Report **2011 Integrated Resource Plan** **Fifth Public Input Meeting, December 15, 2010**

**Meeting Date:** Wednesday, December 15, 2010,

**Meeting Time:** 9:00 am – 3:00 pm (Pacific) / 10:00 am – 4:00pm (Mountain)

**Location:** Portland, Oregon; Salt Lake City, Utah; and telephone conference

### **Organizations Attending**

- Encana
- Energy Trust of Oregon (ETO)
- Idaho Public Service Commission (ID-PSC)
- Northwest Energy Coalition (NVEC)
- Northwest Pipeline GP (NWPGP)
  
- Oregon Public Utility Commission (OPUC)
- PacifiCorp
- Portland General Electric (PGE)
  
- Powder River Basin Resource Council
  
- Renewable Northwest Project (RNP)
- Synapse Energy Economics
  
- Utah Clean Energy (UCE)
- Utah Division of Public Utilities (DPU)
- Utah Office Of Consumer Services (OCS)
- Utah Public Service Commission (UT-PSC)
- Washington Customer (WA Customer)
- Washington Utilities and Transportation Commission (WUTC)
- West Wind Wires (WWW)
- Western Grid Group
- Wyoming Office of Consumer Advocates (WY-OCA)
- Wyoming Public Service Commission (WY-PSC)

*The list of individual meeting attendees is provided as Appendix A.*

### **Meeting Overview**

The integrated resource planning topics covered at this meeting included updates to the IRP schedule, a review of the latest supply-side resource information for portfolio modeling, presentation of the final capacity and energy load & resource balances, set-up attributes for the Company's capacity expansion model (System Optimizer), Monte Carlo stochastic model parameter update, and the proposed 2011 IRP preferred portfolio selection approach.

Pete Warnken, PacifiCorp Manager of Integrated Resource Planning, provided an update on the remaining IRP schedule and summarized recent milestones, such as distribution of the Loss of Load study, dispersed generation resource attributes, and an updated portfolio development case paper.

Jim Lacey, PacifiCorp Resource Development & Construction department, reviewed recent changes to supply-side resource attributes presented in tabular form in the meeting presentation

materials. The focus of the discussion was on geothermal resources, which the Company is modeling based on a consultant's resource potential and cost study completed in August 2010.

Brian Osborn, of PacifiCorp's IRP modeling team, presented the final IRP capacity load & resource balance, summarizing the significant changes made to the version presented to participants at the October 5, 2010, public input meeting. The annual system summer capacity deficit has grown by 200 to 300 MW relative to the October deficit projection due mainly to a higher target planning reserve margin and a smaller assumed capacity contribution from the Idaho irrigation dispatchable load control program. Mr. Osborn also presented the Company's energy position forecast, which is broken out by system on-peak and off-peak hours.

Mr. Warnken and the IRP modeling team summarized key System Optimizer model settings for developing resource portfolios. The IRP team covered changes to the model topology—the key change being the addition of four new topology zones or “bubbles” to better represent transmission constraints in the west side of the system. The IRP modeling team also summarized market purchase (“front office transaction”) limits, described how wind resources are represented in the model, and explained the approach for representing out-year resources.

Connie Clonch, of PacifiCorp's IRP modeling team, presented an overview of the load stochastic parameter update project, as well as described research and findings on characterizing carbon dioxide (CO<sub>2</sub>) price uncertainty in the Monte Carlo stochastic production cost modeling. Ms. Clonch then identified potential future research topics and methodology enhancements to investigate in the area of CO<sub>2</sub> price uncertainty modeling

Finally, Mr. Warnken outlined PacifiCorp's proposed approach for evaluating resource portfolio performance and selecting a preferred portfolio. Mr. Warnken described a two step approach. The first step is an initial portfolio screening where portfolios on the efficient frontier of an “upper-tail cost versus average cost” scatter-plot graph are identified for three CO<sub>2</sub> cost scenarios. The second step is to compare the efficient frontier portfolios on the basis of several portfolio performance measures.

## Discussion Highlights

### *IRP Schedule Update*

1. Mr. Warnken noted that the planned review of System Optimizer modeling results could not be covered at this meeting due to technical modeling problems and continued focus on the all-source Request for Proposals bid evaluation efforts. A modeling results package will be distributed to participants when compiled, followed by a meeting and potential conference call to review the results.
2. Participants discussed the forthcoming IRP model tutorial sessions. Mr. Warnken noted that the process of developing a nondisclosure agreement process with the model vendor, Ventyx Energy, LLC, is taking more time than expected.
3. Utah participants requested a conference call to facilitate another round of discussions on the solar photovoltaic (PV) resource information developed by PacifiCorp's

consultant on the demand-side management potential study update, The Cadmus Group. PacifiCorp agreed to set up the conference call.

### *Supply Side Resource Update*

4. PacifiCorp summarized an earlier conference call with Utah parties on the geothermal resource study for the benefit of the larger public audience. Jim Lacey described the Company's review of the consultant's (Black & Veatch and Geothermix) geothermal resource cost data, indicating that some upward adjustments were made to reflect utility modeling conventions.
5. PacifiCorp mentioned that the Blundell site and new ("greenfield") sites will be modeled separately with costs that include an exploration capital risk premium. The greenfield resource costs will be represented as a cost average for multiple sites identified in the consultant report.
6. The Company emphasized that acquisition of geothermal resources is dependent on a clear signal that regulators will support full recovery of resource development costs. This will be addressed in the 2011 IRP action plan, and is not a modeling issue.
7. A wind project developer expressed concern that PacifiCorp's wind capital costs were too high and capacity factors too low, citing examples based on the latest turbine technologies in the market. PacifiCorp agreed to evaluate and respond to any cost and performance data provided by the wind developer. Mr. Warnken stressed that the remaining IRP schedule precluded updating wind resource attributes for the portfolio modeling. However, the Company would consider conducting a wind resource selection sensitivity study for the preferred portfolio as part of IRP action plan development based on the information received by the wind developer.
8. PacifiCorp answered questions from participants on the modeled attributes of combustion turbines for integrating intermittent renewable resources and load following, as well as utility-scale and distributed energy storage technologies. PacifiCorp mentioned that distributed thermal energy storage is being modeled for the IRP.
9. Participants requested a complete version of the supply side resource attribute table. (A version with only the key cost and performance attributes was presented at this meeting.) PacifiCorp agreed to provide the entire table.

### *Final Load and Resource Balances*

10. PacifiCorp indicated that the load and resource balances incorporate a 13 percent planning reserve margin, which was determined through the loss of load study distributed to participants in November 2010.
11. Participants requested additional details on PacifiCorp's decision to lower the expected capacity contribution of the Idaho irrigation dispatchable load control program by 139 MW, including if such a reduction might apply to the Utah program as well. This was identified as a parking lot item.
12. A participant recommended that the Company consider peak-shaving programs such as the irrigation load control program as a resource for integrating wind, potentially during shoulder periods. PacifiCorp agreed to follow-up on this as a parking lot item.

13. Participants discussed the impact of hedging practices on the load and resource balance, as well as the representation of short-term firm market purchases. PacifiCorp noted that short-term firm products are not incorporated.

### *System Optimizer Model Settings*

14. PacifiCorp described the topology modifications to capture constraints relieved by the Hemingway-Boardman-Bethel (“Cascade Crossing”) transmission project option being investigated as part of the Energy Gateway scenario analysis. PacifiCorp also described a set of wind generation bubbles added to enable assignment of incremental transmission capital costs for wind selected by the model.
15. Mr. Warnken summarized the front office transaction (FOT) limits for east-side markets, which were not reported in the meeting materials. (The east-side FOT limits were still undergoing review and were thus not available at the time the meeting materials were distributed.) These limits include the following:

<b>Market Hub / Proxy FOT Product</b>	<b>Megawatt Limit, 2011 IRP</b>	<b>Megawatt Limit, 2008 IRP Update</b>
Mead / 3 <sup>rd</sup> Quarter 6x16	264 MW, 2012-2014 100 MW, 2015-2016 0 MW, 2017+	300 MW, 2012-2014 100 MW, 2015-2016 0 MW, 2017+
Mona / 3 <sup>rd</sup> Quarter 6x16	200 MW, 2011-2012 300 MW, 2013+	200 MW, 2011-2012 300 MW, 2013+
Utah North / 3 <sup>rd</sup> Quarter 6x16	200 MW	50 MW

16. Eric Arzola, of PacifiCorp’s IRP modeling team, described how wind resources are represented in the model. To clarify the modeling approach, PacifiCorp agreed to provide the data layout and descriptive information, including transmission investment cost information tied to the wind resources.
17. Some participants expressed concern regarding PacifiCorp’s modeling strategy of limiting total system wind additions to 200 MW per year (500 MW per year for modeling CO<sub>2</sub> hard cap cases). Mr. Warnken indicated that this approach addresses the model tendency to select an unrealistic quantity of wind in a given year, and recognizes such issues as procurement constraints and customer rate impacts. PacifiCorp noted that this constraint does not limit the total amount of wind selected, only the timing—it smoothes out the acquisition schedule. PacifiCorp also noted that application of this modeling convention is not intended to constrain the amount of wind that the Company would actually procure based on regulatory and market developments. Discussion on the annual wind addition constraints is provided in the 2008 IRP.
18. Participants asked how incremental transmission costs are allocated to wind resources. PacifiCorp explained that such allocation needs to be a post-modeling exercise given that the model cannot allocate costs.
19. Participants discussed the appropriateness of limiting out-year resources to a single proxy resource type as suggested by one participant. PacifiCorp explained that this approach would prevent representation and analysis of current state resource policies that influence resource selection throughout the 20-year simulation period.

### *Stochastic Modeling Parameter Update*

20. Ms. Clonch indicated that only the stochastic parameters for loads were re-estimated for the 2011 IRP. Time constraints precluded re-estimation and testing of other stochastic parameters.
21. The long term load volatilities were set to zero to avoid unusually high load excursions during the out years of the simulation period. Mr. Warnken mentioned that the stochastic production cost model's vendor, Ventyx, also recommended that the long term load volatilities be set to zero.
22. Ms. Clonch stated that daily loads for a three-year period—2007 through 2009—were applied for estimating short term volatility and correlation parameters needed by the stochastic model. As a parking lot item, PacifiCorp agreed to report the time period for data used to estimate stochastic parameters for the 2008 IRP.
23. Ms. Clonch described research and barriers in determining CO<sub>2</sub> price correlations with market prices. Two approaches were highlighted: estimating correlations using European market data, and using price movements from the Integrated Planning Model (IPM®). The IPM® model is used by PacifiCorp to determine price responses for modeling of CO<sub>2</sub> price forecast scenarios.

### *Proposed Preferred Portfolio Selection Approach*

24. Pete Warnken stated that PacifiCorp does not plan to apply a numerical weighting scheme to performance measures when assessing portfolio ranking as was done for the 2008 IRP. Mr. Warnken explained that while this weighting scheme was intended to make the portfolio evaluation more transparent, it caused controversy for the 2008 IRP because it is inherently subjective.
25. Mr. Warnken asked participants for further feedback—no later mid-January 2011—on the proposed portfolio evaluation approach and specific portfolio performance measures.
26. Participants discussed how supply reliability is captured and measured in the IRP models.
27. One participant recommended that the Company apply statistical tests to determine if the differences in mean portfolio costs (Present Value of Revenue Requirements) for the stochastic production cost studies are statistically significant. Indicating confidence intervals around reported portfolio costs would be useful. PacifiCorp agreed to consider such tests.

## **Responses to Parking Lot Questions and Action Item Follow-up IRP Public Meeting – December 15, 2010**

- 1. Provide a graphic of the entire IRP model system topology used for the 2011 IRP.**

**Response:**

The system model topology is included as Appendix A.

- 2. Provide more background on the decision to reduce the expected Idaho irrigation load control capacity; confirm that the Utah program does not require a similar capacity adjustment at the present time.**

**Response:**

The decision to reduce the capacity contribution in the 2011 IRP was prompted by two factors: 1) the Company's evolving understanding of system constraints, and 2) emerging information on the program's realized impact or curtailment at the point of dispatch. The system constraints have become an issue due to the rapid growth and resulting magnitude of participating loads coupled with the concentration of the participating loads on a select few agriculturally dominant circuits. To maintain system voltages within the required range during the sudden loss of loads characteristic during a program dispatch, the Company has had to devise a modified schedule or phasing of loads in and out of dispatch events as well as to reduce the percentage of participating loads curtailed during any given hour, which effectively reduces the single hour contribution and leads to our planning adjustment. The second factor contributing to adjustment is emerging information from the Company's Idaho program evaluation work. Preliminary results of the evaluation suggest that the diversity of loads running at the point of dispatch is less than previously assumed. While many factors may impact these results from year to year an average result is being assumed for planning to compensate for this preliminary information. Once the program evaluation results have been finalized and the report written, the results will be available for external review.

Regarding the Utah program, a precautionary 15 MW adjustment was made based on the preliminary information from the Idaho program evaluation results. No system constraint adjustment (for voltage stability) was required; the program's size and concentration of participating loads by circuit is not an issue like it is in Idaho.

- 2. Look into the possibility of scheduling irrigation load control to follow wind/solar for system integration purposes.**

**Response:**

Irrigation load control requires day-ahead scheduling, and is therefore not a suitable resource for integrating intermittent resources. For load control programs in general, the Company would need to determine how a program aligns with the optimal timeframes designated by operations personnel for following intermittent resource generation. Operations personnel would then determine if using the program for renewables integration has greater value than using the programs in a traditional manner. Likewise, the Company would study how using the program for renewables integration impacts running the program in a cost-effective manner.

- 3. Describe how storage technologies are modeled in System Optimizer and the Planning and Risk model.**

**Response:**

Energy storage resources in both System Optimizer and Planning and Risk (PaR) are distinguished from other resources by the following three attributes:

- Energy “take” – generation or extraction of energy from a reservoir
- Energy “return” – energy used to fill (or charge) a reservoir
- Storage cycle efficiency – an indicator of the energy loss involved in storing and extracting energy over the course of the take-return cycle.

The models require specification of a reservoir size. For System Optimizer, reservoir size is defined as a megawatt capacity value, whereas in PaR it is defined in gigawatt-hours (GWh). System Optimizer dispatches a storage resource to optimize energy used by the resource subject to constraints such as storage cycle efficiency, the daily balance of take and return energy, and fuel costs (for example, the cost of natural gas for expanding air with gas turbine expanders). To determine the least-cost resource expansion plan, the model accounts for conventional generation system performance and cost characteristics of the storage resource, including investment cost, capacity factor, heat rate (if fuel is used), O&M cost, minimum capacity, and maximum capacity.

In PaR, simulations are conducted on a week-ahead basis. The model operates the storage plant to balance generation and charging, accounting for cycle efficiency losses, in order to end the week in the same net energy position as it began. The model chooses periods to generate and return energy to minimize system cost. It does this by calculating an hourly *value of energy* for charging. This value of energy, a form of marginal cost, is used as the cost of generation for dispatch purposes, and is derived from calculations of system cost and unit commitment effects. For compressed air energy storage (CAES) plants, a heat rate is included as a parameter to capture fuel conversion efficiency. The heat rates entered in both models represent the use of PacifiCorp’s off-peak coal-fired plants.

**4. Provide the complete and updated supply-side resource (SSR) tables.**

**Response:**

The complete and updated supply-side resource tables are included as Appendix C.

**5. Describe in more detail the representation of wind capital costs and capacity factors for portfolio modeling.**

**Response:**

PacifiCorp started with a base set of wind capital costs. The source of these costs is the database of the Integrated Planning Model (IPM®), a proprietary modeling system licensed to PacifiCorp by ICF International. These wind capital costs are divided into high, medium and low levels that differentiate costs by site development conditions. PacifiCorp then applied adjustments to the base capital costs to account for federal tax credits, wind integration costs, fixed O&M costs, and wheeling costs as appropriate. (The cost adjustments are converted into discounted values and added to the base capital cost.)

PacifiCorp uses supply curve information for Western Renewable Energy Zones (WREZs) for determining resource limits by topology bubble. These adjusted capital cost values are used in the System Optimizer model. The table below shows the capital costs and other wind resource attributes for a sample WREZ zone, South Washington (WA\_SO). This particular WREZ corresponds to PacifiCorp’s Yakima topology bubble (see Appendix B).

**Washington South: WREZ WA\_SO zone**

First Year Available	Capacity factor	Cost Level	Adjusted Capital Cost (\$/kW)	WREZ resource depth (MW)	Maximum annual 100 MW units	Maximum Cumulative 100 MW units
2016	29%	1	\$ 3,454	2,566	1	9
		2	\$ 3,927		1	9
		3	\$ 4,633		1	9

To specify the number of discrete wind resources for a topology bubble, PacifiCorp divides the resource limit (or depth) by the number of cost categories—for this sample, three— rounding to the nearest multiple of 100, and then dividing by a 100 MW unit size. While resources are specified in 100 MW blocks, the model can choose a fractional amount of a block.

All resources in a topology bubble are assigned a single capacity factor. Capacity factor is a separate modeled parameter from the capital cost, and is used to scale wind energy shapes used by both the System Optimizer and Planning and Risk models. Wind resources are modeled as must-run units.

**6. Provide details concerning incremental transmission investments assumed for wind resource modeling if such details can be made public at the present time.**

**Response:**

PacifiCorp is still in the process of developing incremental transmission investment costs based on the quantity (nominal capacity) and location of wind determined by the System Optimizer model runs. Note that these incremental costs reflect investment beyond substation interconnection costs, which are already factored into the wind capital costs.

**7. Evaluate and respond to information provided by Wasatch Wind documenting improved capacity factors of newer turbine technologies (i.e., GE Energy’s XLE model) as well as lower capital costs.**

**Response:**

PacifiCorp has not received any data from Wasatch Wind as of the publication date of this meeting report.

8. **Set up a conference call to further discuss solar PV data used for IRP portfolio modeling (requested by Utah Clean Energy).**

**Response:**

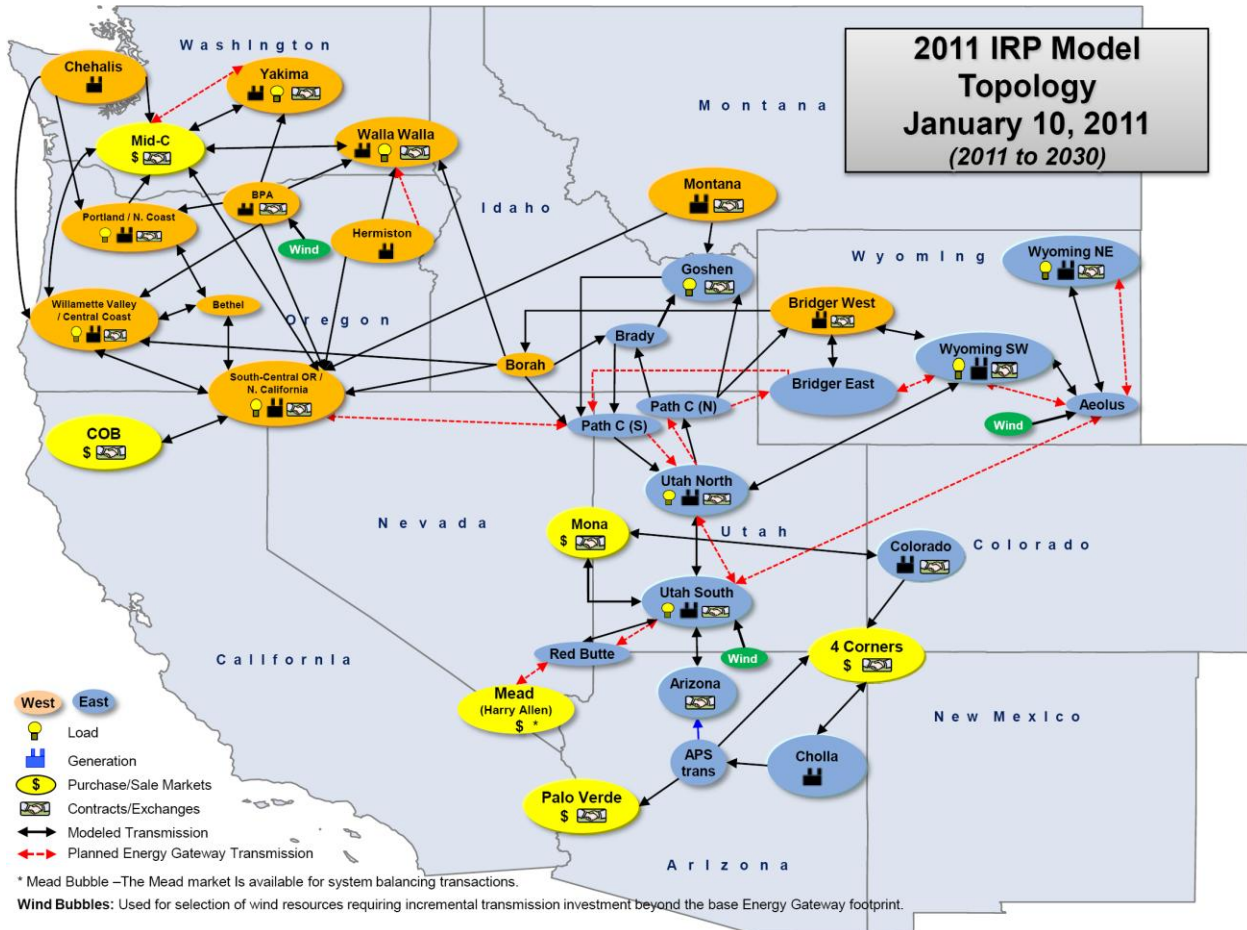
The solar PV data conference call is being scheduled for the week of January 24, 2010. Details of the conference call will be provided when finalized.

## Appendix A: Meeting Attendance List, Individuals

Organization	Name
Encana	Roger Belland
Energy Trust of Oregon (ETO)	Matt Braman
EnXco	Ala Wadi Troy Gagliano
Idaho Public Service Commission (ID-PSC)	Rick Sterling
Northwest Energy Coalition (NVEC)	Steve Weiss
Northwest Pipeline GP (NWPGP)	Teresa Hagins
Oregon Public Utility Commission (OPUC)	Kelcey Brown
PacifiCorp	Romita Biswas Eric Arzola Greg Duvall Brian Osborn Brian Fritz Irene Heng Dan Swan Jim Lacey Michael Liljenwall Brian Osborn Pete Warnken Connie Clonch Dennis Desmarais Susan Rolfe Andrew Hegewald Ian Andrews Sarah Edmonds BJ Moghadam Jon Christensen
Portland General Electric (PGE)	Shelly Saylor
Powder River Basin Resource Council	Shannon Anderson
Renewable Northwest Project (RNP)	Megan Decker
Synapse Energy Economics	Jerry Fisher
Utah Association of Energy Users (UAE)	Gary Dodge Don Hendrickson
Utah Clean Energy (UCE)	Sarah Wright
Utah Division of Public Utilities (DPU)	Charles Peterson Sam Liu

Organization	Name
Utah Division of Public Utilities (DPU) (con't)	Phil Powlick Doug Wheelwright Joni Zenger
Utah Office Of Consumer Services (OCS)	Dan Gimble Bela Vastag
Utah Public Service Commission (UT-PSC)	Joseph Holland Carol Revelt Becky Wilson John Harvey Jerry Maio
Wasatch Clean Air Coalition	Christine Mikell James O'Reilly
Washington Customer (WA Customer)	John Klingele
Washington Utilities and Transportation Commission (WUTC)	David Nightingale
West Wind Wires (WWW)	Roger Hamilton
Western Grid Group	John Wilson
Wyoming Office of Consumer Advocates (WY-OCA)	Denise Parrish
Wyoming Public Service Commission (WY-PSC)	Don Biederman Marci Norby Michelle Bohanan

## Appendix B: 2011 IRP Model Topology



## Appendix C:

### Supply-side Resource Attribute Tables (East and West Side Options)

#### East Side Resource Options

Supply Side Resource Options Mid-Calendar Year 2010 Dollars (\$)	Location / Timing		Plant Details			Outage Information		Costs					Emissions				
	Resource Description	Installation Location	Earliest In-Service Date (Middle of year)	Average Capacity MW - Not Incl. Degradation	Design Plant Life in Years	Annual Average Heat Rate HHV - Incl. Degradation	Maint. Outage Rate	Equivalent Forced Outage Rate	Low Estimate Capital Cost in \$/kW	Base Capital Cost in \$/kW	High Estimate Capital Cost in \$/kW	Var. O&M, \$/MWh	Fixed O&M in \$/kW-yr	SO2 in lbs/MMBtu	NOx in lbs/MMBtu	Hg in lbs/trillion Btu	CO2 in lbs/mmBtu
<b>East Side Resource Options</b>																	
<b>Coal</b>																	
Utah PC without Carbon Capture & Sequestration	Utah	2020	600	40	9,106	4.6%	4.0%	\$2,923	\$3,077	\$3,692	\$0.96	\$38.80	0.100	0.070	0.40	205	
Utah PC with Carbon Capture & Sequestration	Utah	2030	526	40	13,087	5.0%	5.0%	\$5,285	\$5,563	\$6,676	\$6.71	\$66.07	0.050	0.020	0.20	20	
Utah IGCC with Carbon Capture & Sequestration	Utah	2030	466	40	10,823	7.0%	8.0%	\$5,117	\$5,386	\$6,463	\$11.28	\$53.24	0.050	0.011	0.04	20	
Wyoming PC without Carbon Capture & Sequestration	Wyoming	2020	790	40	9,214	4.6%	4.0%	\$3,310	\$3,484	\$4,181	\$1.27	\$36.00	0.100	0.070	0.60	205	
Wyoming PC with Carbon Capture & Sequestration	Wyoming	2030	692	40	13,242	5.0%	5.0%	\$5,985	\$6,299	\$7,559	\$7.26	\$61.37	0.050	0.020	0.30	20	
Wyoming IGCC with Carbon Capture & Sequestration	Wyoming	2030	456	40	11,047	7.0%	8.0%	\$5,794	\$6,099	\$7,318	\$13.52	\$58.00	0.050	0.011	0.06	20	
Existing PC with Carbon Capture & Sequestration (500 MW)	Utah/Wyo	2030	(139)	20	14,372	5.0%	5.0%	\$1,314	\$1,383	\$1,660	\$6.71	\$66.07	0.050	0.011	0.30	20	
<b>Natural Gas (4500 feet)</b>																	
Utility Cogeneration	Utah	2014	10	20	4,974	10.0%	8.0%	\$4,037	\$4,250	\$5,100	\$23.29	\$1.86	0.0000	0.000	0.255	118	
Fuel Cell - Large (solid oxide fuel cell)	Utah	2013	5	30	7,262	2.0%	3.0%	\$1,513	\$1,593	\$1,912	\$0.03	\$8.40	0.0006	0.000	0.255	118	
SCCT Aero	Utah	2014	118	30	9,773	3.8%	2.6%	\$950	\$1,000	\$1,200	\$5.63	\$9.95	0.0006	0.011	0.255	118	
Intercooled Aero SCCT	Utah	2014	279	30	9,379	3.8%	2.9%	\$1,116	\$1,174	\$1,409	\$3.93	\$7.01	0.0006	0.011	0.255	118	
Internal Combustion Engines	Utah	2014	301	30	8,806	5.0%	1.0%	\$1,093	\$1,150	\$1,380	\$5.50	\$6.49	0.0006	0.017	0.255	118	
SCCT Frame (2 Frame "F")	Utah	2014	362	35	10,446	3.8%	2.7%	\$941	\$991	\$1,189	\$7.16	\$5.41	0.0006	0.050	0.255	118	
CCCT (Wet "F" 1x1)	Utah	2014	270	40	7,302	3.8%	2.7%	\$1,122	\$1,181	\$1,418	\$2.98	\$13.48	0.0006	0.011	0.255	118	
CCCT Duct Firing (Wet "F" 1x1)	Utah	2014	43	40	8,869	3.8%	2.7%	\$458	\$482	\$579	\$0.55	\$0.00	0.0006	0.011	0.255	118	
CCCT (Wet "F" 2x1)	Utah	2014	539	40	6,885	3.8%	2.7%	\$1,014	\$1,067	\$1,280	\$2.98	\$8.19	0.0006	0.011	0.255	118	
CCCT Duct Firing (Wet "F" 2x1)	Utah	2014	86	40	8,681	3.8%	2.7%	\$511	\$538	\$646	\$0.55	\$0.00	0.0006	0.011	0.255	118	
CCCT (Dry "F" 2x1)	Utah	2015	512	40	6,963	3.8%	2.7%	\$1,049	\$1,104	\$1,325	\$3.35	\$9.69	0.0006	0.011	0.255	118	
CCCT Duct Firing (Dry "F" 2x1)	Utah	2015	85	40	8,934	3.8%	2.7%	\$511	\$538	\$646	\$0.55	\$0.00	0.0006	0.011	0.255	118	
CCCT (Wet "G" 1x1)	Utah	2015	333	40	6,751	3.8%	2.7%	\$1,061	\$1,117	\$1,341	\$4.56	\$6.75	0.0006	0.011	0.255	118	
CCCT Duct Firing (Wet "G" 1x1)	Utah	2015	72	40	9,021	3.8%	2.7%	\$449	\$473	\$567	\$0.36	\$0.00	0.0006	0.011	0.255	118	
CCCT Advanced (Wet "H" 1x1)	Utah	2018	400	40	6,602	3.8%	2.7%	\$1,172	\$1,233	\$1,480	\$4.56	\$6.75	0.0006	0.011	0.255	118	
CCCT Advanced Duct Firing (Wet "H" 1x1)	Utah	2018	75	40	9,021	3.8%	2.7%	\$575	\$605	\$726	\$0.36	\$0.00	0.0006	0.011	0.255	118	
<b>Other - Renewables</b>																	
Wyoming Wind (35% CF)	Wyoming	2012	100	25	n/a	n/a	n/a	\$2,015	\$2,239	\$2,686	\$0.00	\$31.43	0.000	0.000	0.000	0	
Utah Wind (29% CF)	Utah	2012	100	25	n/a	n/a	n/a	\$2,015	\$2,239	\$2,686	\$0.00	\$31.43	0.000	0.000	0.000	0	
East Side Geothermal (Dual Flash, 80MW max per cite)	Utah	2015	35	40	n/a	5.0%	5.0%	\$4,066	\$4,280	\$5,135	\$5.94	\$110.85	0.000	0.000	0.000	0	
Advance Battery Storage	All	2015	5	30	11,000	1.9%	5.0%	\$1,924	\$2,025	\$2,431	\$10.00	\$1.00	0.100	0.400	3.000	205	
Pumped Storage	Nevada	2020	250	50	12,500	5.0%	5.0%	\$1,636	\$1,723	\$2,067	\$4.30	\$4.30	0.100	0.400	3.000	205	
Compressed Air Energy Storage (CAES)	Wyoming	2015	350	30	11,980	3.8%	2.7%	\$1,241	\$1,307	\$1,568	\$5.50	\$3.80	0.001	0.011	0.255	118	
Nuclear (Advance Fission)	Idaho	2030	1,600	40	10,710	7.3%	7.7%	\$5,041	\$5,307	\$6,368	\$1.63	\$146.70	0.000	0.000	0.000	0	
Solar (Thin Film PV) - 19% CF	Utah	2012	5	25	n/a	n/a	n/a	\$3,982	\$4,191	\$5,030	\$0.00	\$59.50	0.000	0.000	0.000	0	
Solar Concentrating (Thermal Trough, NG backup) - 25% solar	Utah	2014	250	30	n/a	n/a	n/a	\$3,831	\$4,033	\$4,839	\$0.00	\$120.99	0.000	0.000	0.000	0	
Solar Concentrating (Thermal Trough, NG backup) - 30% solar	Utah	2014	250	30	n/a	n/a	n/a	\$4,293	\$4,519	\$5,423	\$0.00	\$135.56	0.000	0.000	0.000	0	

## West Side Resource Options

Supply Side Resource Options Mid-Calendar Year 2010 Dollars (\$)	Location / Timing		Plant Details			Outage Information		Costs					Emissions			
	Installation Location	Earliest In-Service Date (Middle of year)	Average Capacity MW - Not Incl. Degradation	Design Plant Life in Years	Annual Average Heat Rate HHV - Incl. Degradation	Maint. Outage Rate	Equivalent Forced Outage Rate	Low Estimate Capital Cost in \$/kW	Base Capital Cost in \$/kW	High Estimate Capital Cost in \$/kW	Var. O&M, \$/MWh	Fixed O&M in \$/kW-yr	SO2 in lbs/MMBtu	NOx in lbs/MMBtu	Hg in lbs/trillion Btu	CO2 in lbs/mmBtu
<b>Resource Description</b>																
<b>West Side Resource Options (1500 feet)</b>																
<b>Natural Gas</b>																
Utility Cogeneration	Northwest	2014	0	20	4,974	10.00%	8.00%	\$3,670	\$3,863	\$4,636	\$21.17	\$1.69	0.00000	0.00000	0.255	118
SCCT Aero	Northwest	2014	130	30	9,773	3.85%	2.60%	\$864	\$909	\$1,091	\$5.12	\$9.04	0.00060	0.01102	0.255	118
Intercooled Aero SCCT	Northwest	2014	307	30	9,379	3.85%	2.90%	\$1,014	\$1,067	\$1,281	\$3.57	\$6.37	0.00060	0.01102	0.255	118
Internal Combustion Engines	Northwest	2014	331	30	8,806	5.00%	1.00%	\$993	\$1,046	\$1,255	\$5.50	\$6.49	0.00060	0.01652	0.255	118
SCCT Frame (2 Frame "F")	Northwest	2014	405	35	10,446	3.85%	2.70%	\$856	\$901	\$1,081	\$6.51	\$4.92	0.00060	0.04950	0.255	118
CCCT (Wet "F" 1xl)	Northwest	2014	296	40	7,302	3.85%	2.70%	\$1,020	\$1,074	\$1,289	\$2.71	\$12.25	0.00060	0.01100	0.255	118
CCCT Duct Firing (Wet "F" 1xl)	Northwest	2014	47	40	8,869	3.85%	2.70%	\$416	\$438	\$526	\$0.50	\$0.00	0.00060	0.01100	0.255	118
CCCT (Wet "F" 2xl)	Northwest	2014	593	40	6,885	3.85%	2.70%	\$922	\$970	\$1,164	\$2.71	\$7.45	0.00060	0.01100	0.255	118
CCCT Duct Firing (Wet "F" 2xl)	Northwest	2014	95	40	8,681	3.85%	2.70%	\$465	\$489	\$587	\$0.50	\$0.00	0.00060	0.01100	0.255	118
CCCT (Wet "G" 1xl)	Northwest	2015	367	40	6,751	3.85%	2.70%	\$965	\$1,016	\$1,219	\$4.14	\$6.13	0.00060	0.01100	0.255	118
CCCT Duct Firing (Wet "G" 1xl)	Northwest	2015	80	40	9,021	3.85%	2.70%	\$408	\$430	\$516	\$0.33	\$0.00	0.00060	0.01100	0.255	118
CCCT Advanced (Wet "H" 1xl)	Northwest	2018	440	40	6,602	3.85%	2.70%	\$1,065	\$1,121	\$1,346	\$4.14	\$6.13	0.00060	0.01100	0.255	118
CCCT Advanced Duct Firing (Wet "H" 1xl)	Northwest	2018	83	40	9,021	3.85%	2.70%	\$523	\$550	\$660	\$0.33	\$0.00	0.00060	0.01100	0.255	118
<b>Other - Renewables</b>																
Oregon / Washington Wind (29% CF)	Northwest	2012	50	25	n/a	n/a	5.00%	\$2,145	\$2,383	\$2,860	\$0.00	\$31.43	0.00000	0.000	0.0	0
Greenfield Geothermal (Binary, 408MW max per cite)	Northwest	2015	35	40	n/a	n/a	5.00%	\$5,862	\$6,170	\$7,404	\$5.94	\$209.40	0.00000	0.000	0.0	0
Solar (Thin Film PV) - 19% CF	Northwest	2012	5	25	n/a	n/a	n/a	\$3,982	\$4,191	\$5,030	0	\$59.50	0	0	0	0
<b>West Side Resource Options at ISO Conditions (Sea Level)</b>																
<b>Natural Gas</b>																
Utility Cogeneration	Northwest	2014	0	20	4,974	10.00%	8.00%	\$3,511	\$3,695	\$4,434	\$21.17	\$1.69	0.00000	0.00000	0.255	118
SCCT Aero	Northwest	2014	135	30	9,773	2.00%	2.60%	\$826	\$870	\$1,043	\$4.89	\$8.65	0.00060	0.0110	0.255	118
Intercooled Aero SCCT	Northwest	2014	321	30	9,379	3.85%	2.90%	\$970	\$1,021	\$1,225	\$3.42	\$6.10	0.00060	0.0110	0.255	118
Internal Combustion Engines	Northwest	2014	346	30	8,806	3.85%	1.00%	\$950	\$1,000	\$1,200	\$5.50	\$6.49	0.00060	0.0165	0.255	118
SCCT Frame (2 Frame "F")	Northwest	2014	423	35	10,446	5.00%	2.70%	\$818	\$861	\$1,034	\$6.23	\$4.70	0.00060	0.0495	0.255	118
CCCT (Wet "F" 1xl)	Northwest	2014	310	40	7,302	3.85%	2.70%	\$976	\$1,027	\$1,233	\$2.59	\$11.72	0.00060	0.0110	0.255	118
CCCT Duct Firing (Wet "F" 1xl)	Northwest	2014	49	40	8,869	3.85%	2.70%	\$398	\$419	\$503	\$0.48	\$0.00	0.00060	0.0110	0.255	118
CCCT (Wet "F" 2xl)	Northwest	2014	620	40	6,885	3.85%	2.70%	\$881	\$928	\$1,113	\$2.59	\$7.12	0.00060	0.0110	0.255	118
CCCT Duct Firing (Wet "F" 2xl)	Northwest	2014	99	40	8,681	3.85%	2.70%	\$445	\$468	\$562	\$0.48	\$0.00	0.00060	0.0110	0.255	118
CCCT (Wet "G" 1xl)	Northwest	2015	383	40	6,751	3.85%	2.70%	\$923	\$971	\$1,166	\$3.96	\$5.87	0.00060	0.0110	0.255	118
CCCT Duct Firing (Wet "G" 1xl)	Northwest	2015	83	40	9,021	3.85%	2.70%	\$391	\$411	\$493	\$0.31	\$0.00	0.00060	0.0110	0.255	118
CCCT Advanced (Wet "H" 1xl)	Northwest	2018	460	40	6,602	3.85%	2.70%	\$1,019	\$1,073	\$1,287	\$3.96	\$5.87	0.00060	0.0110	0.255	118
CCCT Advanced Duct Firing (Wet "H" 1xl)	Northwest	2018	86	40	9,021	3.85%	2.70%	\$500	\$526	\$632	\$0.31	\$0.00	0.00060	0.0110	0.255	119
<b>Other - Renewables</b>																
Oregon / Washington Wind (29% CF)	Northwest	2012	100	25	n/a	n/a	5.00%	\$2,145	\$2,383	\$2,860	\$0.00	\$31.43	0.00000	0.00000	0.000	0
Biomass	Northwest	2015	50	30	10,979	4.60%	4.00%	\$3,334	\$3,509	\$4,211	\$0.96	\$38.80	0.10000	0.35000	0.400	205
Hydrokinetic (Wave, Buoy) - 21% CF	Northwest	2020	100	20	n/a	n/a	n/a	\$5,539	\$5,831	\$6,997	\$0.00	\$174.92	0.00000	0.00000	0.000	0
Solar (Thin Film PV) - 19% CF	Northwest	2012	5	25	n/a	n/a	n/a	\$3,982	\$4,191	\$5,030	\$0.00	\$56.91	0.00060	0.0110	0.255	118